During the March 18 Entergy Regional State Committee (E-RSC) Meeting, the E-RSC Working Group identified the following questions or action items for your immediate attention. Please provide us this information by the date identified below. If you have any clarifying questions or would like to discuss the timelines provided, please contact Sam Loudenslager, at 501-682-5824 or via email at sloudenslager@psc.state.ar.us.

1. **Redispatch Costs**: To address concerns about the lack of a redispatch cost allocation method, the E-RSC WG is interested in reviewing cost allocation proposals. **Action Requested**: Please draft a detailed proposal to allocate redispatch costs. This proposal should be submitted to the E-RSC Working Group by email to: [ERSCWorkingGroup@SPP.org](mailto:ERSCWorkingGroup@SPP.org) by 4:00 pm on April 15, 2010.

The ERSC WG expects that responses to this request will be accurate and complete. To the extent that you believe additional information or data is required to ensure an accurate response, you have an obligation to timely identify and provide that information or data in good faith.

The E-RSC Working Group will request additional information in the coming weeks and in the meantime, appreciates your assistance by providing the information and in the timeframe requested.
Treatment of Redispatch Cost

- Redispatch is essentially handled two ways:
  - By each individual network customer when Native Network Load ("NNL") obligation is assigned by the Reliability Coordinator during a TLR Level 5
    - Each network customer then determines which units to redispatch by analyzing the relevant Generator Shift Factors ("GSF") of its Designated Network Resources ("DNR")
  - During an LAP by the use of GSF across the affected flowgates
    - The redispatch is strictly determined by the GSF regardless of the cost of one resource versus another
      - i.e. an $20 coal unit could be redispached because it has a GSF of 10%, and $65 steam unit could be left untouched because it has a GSF of less than 10%

- Neither process adheres to current tariff requirements
Order No. 888 stipulated pro-rata curtailment across each Transmission Provider’s entire system

Order No. 890 clarified the obligation of transmission providers to provide “reliability redispatch” service:

➢ “The network service ‘reliability redispatch’ provisions in pro forma OATT sections 33.2 and 33.3 were established in Order No. 888 to ensure comparable reliable service to network customers as the service that the transmission provider provides to its bundled retail load.

➢ These redispatch procedures further provide for redispatch of not just the transmission provider's own resources, but all network resources, including those of network customers, when required to maintain the reliability of the system and avoid the need for curtailments.”

➢ Order No. 890 at P 1632.

See also 890 at P 902:

➢ “Reliability redispatch is required, when feasible, to relieve system constraints that would otherwise cause curtailment of the network customer or transmission provider loads. To provide reliability redispatch, the transmission provider rediscatches all network resources and transmission provider resources on a least-cost basis.”
OATT Requirements on Redispatch

- **Section 33.2 of the Entergy OATT: Transmission Constraints**
  - During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider’s system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider’s system.
  - To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispachting resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispach all Network Resources and the Transmission Provider’s own resources on a least-cost basis without regard to the ownership of such resources. Any redispach under this section may not unduly discriminate between the Transmission Provider’s use of the Transmission System on behalf of its Native Load Customers and any Network Customer’s use of the Transmission System to serve its designated Network Load.

- **Section 33.3 of the Entergy OATT: Cost Responsibility for Relieving Transmission Constraints:**
  - Whenever the Transmission Provider implements least-cost redispach procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispach cost based on their respective Load Ratio Shares.

- **Section 34.2 of the Entergy OATT: Redispach Charge:**
  - The Network Customer shall pay a Load Ratio Share of any redispach costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispach costs in accordance with Section 33, such amounts shall be credited against the Network Customer’s bill for the applicable month.

- **Load Ratio Share is defined in the Entergy OATT as:**
  - “the Ratio of a Transmission Customer’s Network Load to the Transmission Provider’s total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.”
The Network Operating Agreement Specifies how Redispatch Costs are Calculated.

- Entergy NITS Agreement specifies that:
  - Redispatch Procedures may be implemented by the Transmission Provider when a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission System or adversely affect the economic operations of the Transmission Provider or the Transmission Customer or to meet long-term firm transmission requirements under the Point-to-Point Tariff.
  - The procedure for such redispatch of the generation resources of the Transmission Provider and the Customer(s) is attached as Appendix B. This procedure is not for the purpose of sustaining non-firm service, which is curtailable.

- Appendix B sets forth the procedure Entergy must use in redispatching resources:
  1. Determine the Network and other resources that will most effectively relieve the transmission constraint.
  2. The Transmission Provider, in coordination with the Network Integration Service Customer whose Network and other resources may be redispatched, shall determine the incremental cost of each redispatch option that may relieve the transmission constraint. Redispatch shall then be implemented in the nominally least cost manner.
  3. Redispatch shall continue until no longer necessary to relieve the transmission constraint.
  4. The Transmission Provider and the Transmission Customer shall calculate their respective redispatch costs for the appropriate period and submit them to the Transmission Provider monthly, within 5 working days of the end of the calendar month.

- Appendix B also specifies that each party shall bill the other for its redispatch costs. Then the “Transmission Provider shall total the previous month’s redispatch costs, determine the Transmission Provider’s and each Network Customer’s Load Ratio Share of the costs, and submit a bill to each Customer within 10 working days of receipt of the costs.”
NRG Proposal on Redispatch

- OATT provisions regarding redispatch have been in effect for 14 years
  - NRG recommends that after 14 years, Entergy follow the tariff
MEMORANDUM

VIA EMAIL

TO: ENTERGY REGIONAL STATE COMMITTEE (ERSC) WORKING GROUP (ERSCWorkingGroup@SPP.org)

FROM: ARKANSAS CITIES; ZACHARY D. WILSON

DATE: APRIL 15, 2010

RE: ERSC WORKING GROUP REQUEST FOR STAKEHOLDER INFORMATION ON REDISPATCH COST ALLOCATION

I. BACKGROUND

The following proposal is being submitted by Arkansas Cities (AC). AC includes: the Conway Corporation, the West Memphis Utilities Commission, the City of Benton, Arkansas, the City of Osceola, Arkansas, the City of Prescott, Arkansas and the Hope Water & Light Commission.

The ERSC previously met on March 18, 2010. At the March 18, 2010 meeting, the ERSC Working Group identified several questions or action items, one issue being directed to Jennifer Vosburg (NRG and LaGen) and stakeholders in general. This issue requested information or proposals from stakeholders on redispatch cost allocation.

II. E-RSC WORKING GROUP REQUEST FOR INFORMATION

Redispatch Costs: To address concerns about the lack of a redispatch cost allocation method, the E-RSC WG is interested in reviewing cost allocation proposals. Action Requested: Please draft a detailed proposal to allocate redispatch costs. This proposal should be submitted to the E-RSC Working Group by email to: ERSCWorkingGroup@SPP.org by 4:00 pm on April 15, 2010.
III. AC RESPONSE TO E-RSC WG REQUEST FOR INFORMATION; PROPOSAL FOR REDISPATCH COST ALLOCATION

The following is the proposal from AC for a cost allocation method for redispatch costs. The redispatch cost allocation proposal would most likely require revisions to Entergy OATT Section 34.2, and possibly other sections of the OATT including Section 33. The following proposal from AC is not intended to necessarily be a comprehensive proposal, but is for general discussion purposes. New language proposed by AC under Section 34.2 of the Entergy OATT is used as a guide. The current OATT Section 34.2 states:

34.2 Redispach Charge:

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

AC suggestions are:

1. Except in the case of units owned in whole or in part by non-affiliates, redispatch costs will not be allocated to customers under their load ratio share if the Transmission Provider uses redispatch of units for strictly economic reasons. Costs associated with redispatch for reliability, transmission loading relief or redispatch necessary to accommodate requests for service from Transmission customers would remain allocated according to their respective load ratio share.

2. Also, Transmission customers will only be allocated redispatch costs, if any, pursuant to Attachment V, according to the MWh bought or sold in the Weekly Procurement Process by the Transmission Customer. If the Transmission Customer has not bought or sold energy under the Weekly Procurement Process, the Transmission Customer will not be allocated redispatch costs pursuant to Attachment V. (NOTE: This section may not be necessary if recent intent is to eliminate redispatch charges associated with Attachment V altogether.)

3. Transmission Customers that own or co-own units on the system will be credited and compensated for amounts due the Transmission Customer for redispatch costs associated with the Transmission Customers proportionate ownership shares in the units so redispatched.
IV. CONCLUSION

AC appreciates the concerns of the ERSC and welcomes further requests by the ERSC from stakeholders on these matters. If there are any questions concerning this proposal, do not hesitate to contact us at any time.
DATE:        April 8, 2010

FROM:  E-RSC Working Group (ERSCWorkingGroup@SPP.org)

TO:  Carl Monroe
     Jay Caspary

SUBJ: Request for Information

During the March 18 Entergy Regional State Committee (E-RSC) Meeting, the E-RSC Working Group identified the following questions or action items for your immediate attention. Please provide us this information by the date identified below. If you have any clarifying questions or would like to discuss the timelines provided, please contact Sam Loudenslager, at 501-682-5824 or via email at sloudenslager@psc.state.ar.us.

1. The E-RSC asked the ICT to provide details and analysis on transmission sales that precede TLR events to determine if the sales are a contributing factor. Stakeholders are concerned that there is not enough coordination between those in the ICT selling transmission and those responsible for reliability that call TLR events. As part of the ongoing ICT stakeholder process, the ICT initiated a review of their activities and identified an initial list of seven issues. The ICT has committed to put in place actions to resolve these issues. **Action Requested:** The ICT will report back to the E-RSC WG with a summary of each issue. For each issue, the ICT will explain what actions they have identified to mitigate the issue. For any issue that requires additional analysis, the ICT will propose a work plan identifying how and when the ICT intends to resolve the issue. For any issue that the ICT determines resolution is beyond their abilities or requires additional regulatory approvals, the ICT will explain this in sufficient detail. This report is due via email to ERSCWorkingGroup@SPP.org and by 4:00 CDT, April 15, 2010. The ICT will assess whether this concern is valid. If not valid, the E-RSC WG will ask stakeholders for additional evidence.

2. **WPP Performance** – The ICT will assess the resource and operational impacts if the WPP expanded to include off-peak hours. **Action Requested:** The ICT will provide to the E-RSC Working Group an analysis of additional resources and costs that would be incurred to expand the WPP to include off-peak hours and the time needed to implement the expansion. The timeframe does not need to include the time needed to make any necessary FERC 205 filing to change the OATT language. This analysis is due by 4:00 CDT on April 15, 2010, via email to: ERSCWorkingGroup@SPP.org.
The ERSC WG expects that responses to this request will be accurate and complete. To the extent that you believe additional information or data is required to ensure an accurate response, you have an obligation to timely identify and provide that information or data in good faith.

The E-RSC Working Group will request additional information in the coming weeks and in the meantime, appreciates your assistance by providing the information and in the timeframe requested.
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**Response:** Please see Attachment 1.
2. **WPP Performance** – The ICT will assess the resource and operational impacts if the WPP expanded to include off-peak hours. **Action Requested:** The ICT will provide to the E-RSC Working Group an analysis of additional resources and costs that would be incurred to expand the WPP to include off-peak hours and the time needed to implement the expansion. The timeframe does not need to include the time needed to make any necessary FERC 205 filing to change the OATT language. This analysis is due by 4:00 CDT on April 15, 2010, via email to: ERSCWorkingGroup@SPP.org.

**Response:** Please see Attachment 2.

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Attachment 1
Discussion of Issues of AFC Calculations within the Transmission Service Request Process

Per the current Entergy OATT Attachment C and the ICT Contract, transmission service is sold based on the AFC models created based on the processes in those documents by Entergy. The inputs into these models determine the base flow on each of the AFC flowgates and the Transfer Distribution Factor (TDF) for each TSR requested on the Entergy OASIS. These inputs include, but are not limited to, Generation and Load Forecasting, Unit Commitment, Generation and Transmission Outages, External Control Area Dispatch and Interchange, and OASIS Reservations. These inputs have often differed from the real-time operations of the Entergy system. Note also, that there are also differences in the processes used to sell transmission service and those processes used to curtail service in a TLR event.

Below is a description of issues within these processes and are discussed below:

Load Forecasting:

Attachment C of the Entergy OATT states that the Load Serving Entity (LSE) will submit a load forecast to be used in the AFC models. For those LSEs that do not submit a load forecast, the load is determined based on a percentage of the Entergy load provided by Entergy’s System Planning Organization (SPO) daily. Also, understand that the load information for the next day is generally not available until the 9:30 AM RFCalc resync. This data is not reflected in the AFC calculations until after 10:00 AM and thus is not used for next day or any service evaluated until after that time.

The process for the LSE to submit the load forecast is detailed in Attachment C of the Entergy OATT. The LSEs are required to submit the data to Entergy in a very specific format that is different than the other ways they are required to submit the data to their Reliability Coordinator. As such they have not been willing to incur incremental costs to provide the specific format in the daily process. There are currently no initiatives to make changes to the load forecasting process in the AFC models. The ICT is working to perform analysis to determine the scope of the differences between the actual and forecasted loads. A possible alternative is that the ICT use this analysis to suggest use of historical data for load forecasting.
Generation Dispatch

Attachment C of the Entergy OATT states that the LSE will submit a generation dispatch to be used in the AFC models to serve that entities load. There are limitations on the data that can be submitted and how it can be used. This is particularly acute for those LSEs that have short-term resources in their own unit commitment, since the unit commitment file format can only include long-term resources as part of the dispatch. The current reservation stacking option requires that each be reservation based and only split by on-peak and off-peak, not by hour. Additionally, that reservation is fully represented even when the LSE may only want to commit a partial amount. If the resource is external to Entergy, and not modeled in the AFC process of Entergy, the representation is less granular (represented as coming from the external control area, not the specific resource). These requirements limit the ability to create the most accurate dispatch possible. For those LSEs that do not submit a generation dispatch, the load is met by modeling reservations in reverse queue order until the load is met, the last reservation confirmed will be the first modeled to meet load, whether this service is intended to be used or not. Once the load has been met, no additional reservation will be modeled. As above generation information submitted by any LSE for the next day is generally not available or used in the models until after 10:00 AM.

The reverse queue order modeling is also used to meet any shortfall for Entergy load which is not met by the Unit Commitment file and Reservation Stack file provided by SPO. There are currently no initiatives to make changes in the process used to set the generation dispatch in the AFC models. A possible alternative is that the ICT would use historical data to set the dispatch.

Counterflow

Counterflow is the “relief” that is provided on a facility by modeling the service required to meet load and the Point to Point transaction reserved on the Entergy system. Entergy includes 100% counterflow for all transmission service that is modeled in the AFC models, meaning that all reservations are used even though they might not be simultaneously used. This is not as significant for Network Service as Entergy only models the amount of Network Service that is needed to meet load. A possible impact of this is that if the Network Service is modeled different than what is actually scheduled and used in real-time, the counterflow being applied for that service would be incorrect.

Entergy has performed studies to determine the amount of counterflow which should be utilized in the AFC models. Those results were provided to the Near-Term Transmission Issues Working Group (NTTIWG). While it is possible to remove the determined amount of counterflow from the Study Horizon models this has not been completed yet. This is due to the AFC Business
Practices referenced in the Attachment C filing not being finalized. The ICT has requested the AFC Business Practice several times over the past year, but has not received a final version. The counterflow amounts should be reflected in the AFC Business Practices.

For the Operating and Planning Horizons, additional steps would need to be performed to determine the ability to remove counterflow from the models. These steps would include ensuring that the software is capable of accurately removing the required amount of counterflow.

**Transmission Distribution Factor (TDF) Determination**

The calculation of a TDF for selling service in the AFC process differs from the calculation used in the Interchange Distribution Calculation (IDC) for TLR events. The TDF in the AFC process is determined by simulating a transaction from the Source subsystem to the Sink subsystem. The TDF is dependent on the definition of the Source and Sink subsystems. The sink subsystem of a Network Customer is defined as the units designated as long-term network resources for that customer. If that customer has no long-term network resources, the sink subsystem is defined as all of Entergy. For transactions used to meet Entergy load, the TDF is impacted by the unit commitment provided by SPO and the participation factor file created by Entergy Transmission.

Assuming that only long-term designated network resources will be displaced with the confirmation of additional network service is not necessarily reflective of the actual dispatch of a customer’s resources. There are currently no initiatives underway to make changes to the TDF calculations performed by RFCalc. One possible alternative that has previously been discussed is to create the TDF based on a generation to load calculation. This would require significant changes to the current RFCalc software.

In the April 2009 filing of Attachment C, Entergy stated the difference in opinions between the ICT and Entergy on how load-only control areas, or any area with insufficient resources to meet load, should be handled. Entergy requested guidance from FERC on this issue.

**AFC Flowgates Vs. IDC Flowgates**

Entergy maintains a list of approximately 300 thermal flowgates in which transmission service is evaluated in the AFC process. This list of flowgates may be different than the ones in the IDC. In these instances, the RC may TLR on flowgates which are not modeled in the AFC process,
and therefore, those would not have limited the sale of service. The RC also has the ability to add flowgates “on the fly”. This does not happen in the AFC process. It generally takes days to add a new temp flowgate to the AFC process.

The differences in the IDC list of flowgates and the list of AFC flowgates is not something that can be easily eliminated. Entergy monitors 300 thermal flowgates in the AFC process. These flowgates are reviewed on an annual basis and changes are made as necessary.

### Qualify Facility (QF) Puts

QF puts are not modeled in the Entergy AFC models. Therefore, any impact of this generation on the transmission facility is not accounted for in the models.

In its April 2009 filing of Attachment C, Entergy requested guidance from the Commission on how to handle QF puts in the models. Entergy stated that the prospect of changing this practice raised potential regulatory policy considerations and requested guidance regarding whether the AFC models could be modified to incorporate assumptions about QF dispatch levels in light of the fact that those facilities have no obligation to run and have not reserved transmission service.

### External Control Area Modeling and Loop Flows

Currently, Entergy has really limited data coordination with the external control areas for determining accurate generation dispatch and interchange. The AFC modeling for the external control areas generally does not provide an accurate model of the loop flows created on the Entergy system, largely between Southern Company and Tennessee Valley Authority. Also, the AFC modeling generally does not provide an accurate dispatch of the resources within these external control areas which may have significant impacts on the flowgates in the AFC models. Requests have continuously been made for Entergy to make improvements to its modeling practices in regards to external control area modeling.

The AFC Modeling Improvements Task Force began meeting in June 2009 to discuss possible improvements to the AFC models, including the external control area dispatch and Net Interchange issue. Of the possible alternative considered for improvements, the stakeholders determined that the desirable approach was to pursue the coordination of reservation data with the neighboring entities, as well as requesting from that entity a merit order dispatch of their
generation. Since those meetings, only one small external control area has begun providing data for use in the Entergy AFC models. Part of the reason is that Entergy is required to post this information publicly which those entities feel would release confidential information. For those external control areas for which data is not being provided, other possible solutions need to be explored to allow for more accurate modeling in the AFC models. The current process often allows for large deviances between the AFC model and what actually happens in real-time.

In the April 2009 Attachment C filing, Entergy stated implementation of more specific changes may require further development activities (including software modifications) and will be subject to NERC reliability standards that had not yet been approved by the Commission. With the ruling of Order 729, Entergy should begin to consider changes to its current practice for modeling the dispatch and net interchange for the external control areas.

**Override of AFC values during TLR**

Due to the differences in the AFC models and real-time, there are often times when AFCs are shown to be available on a flowgate that is in TLR. This allows transmission service to continue to be sold which impacts that flowgate in TLR. The ICT is finalizing a process which will allow the AFC values on a particular flowgate to be set to 0 MW which that flowgate is congested in real-time. Non-Firm service, which has a 3% impact or greater, will then be refused on that flowgate. This process will be presented for final comments at the May NTTIWG meeting, and implemented immediately thereafter.
Attachment 2
As part of the work being requested by the WPP Issues Working Group (WPPIWG) the ICT has recently completed analysis to look at an expansion of the on-peak hours for the WPP. During this analysis, all hours were analyzed but generally additional hours led to model instability. In the end, the ICT determined that the most feasible hours to investigate further would be to add a single hour to the beginning and the end of the current on-peak hours. This would increase the on-peak offer hours to hours ending 6 and 23 versus the current hours ending 7 and 22. If it is decided that this 2 hour expansion should be implemented the ICT could do so with no additional costs or resources. The ICT could not speculate on any additional costs or resources which might be necessary for Entergy. In the February WPPIWG this analysis was delivered by the ICT:

“Agenda Item 5 – Update on Limitation of On-Peak Only Offer Period Testing

Nick Parker stated that the on-peak offer period testing was conducted on 12 WPP operating weeks throughout the year to capture diverse seasonal load shapes. Nick explained that the current on-peak offer period is from hours 7 to 22 and that the testing expanded the on-peak offer period to hours 6 to 23.

The testing was based on existing offers submitted for the WPP operating weeks evaluated. Nick explained that adjustments to those offers were made relative to the extension of the on-peak hours. For example, in the event a flexible offer was originally available from hours 7 to 22, then the available hours were extended to hours 6 through 23. Other constraints such as minimum downtimes and minimum runtimes were adjusted to meet the new on-peak hours. If the offer was a block and it was available from hours 7 to 22, then the hours were extended to hour 6 to 23 and the minimum energy was adjusted to accommodate the extended on-peak period. If an offer’s available hours were less than hours 7 to 22, it was not adjusted.

Nick reviewed the summary spreadsheet provided (Attachment 3 – Limitation of On-Peak Offer Testing). All sensitivities were compared to SCUC runs with the production dataset and were executed on the current SCUC engine. Savings greater than or less than 10% of the original savings value was considered a change in savings. Nick reported that 6 of the 12 weeks tested selected an additional offer and 5 of those 6 weeks yielded an increase in violations. Stakeholder questioned what type of violations increased. Antoine Lucas stated that the increase in violations was primarily due to the flexibility constraint.

Stakeholder questioned if around the clock offer testing was performed. Antoine stated that this round of testing initially encompassed around the clock offers but was reduced to hours 6 to 23 due to excessive violations.

Stakeholder questioned why 5 test cases increased the offer selection but decreased savings. Antoine stated that the model is non-linear and heuristic based. As a result of this, an absolute global optimum solution is unlikely to occur and changes in the model’s commitment decisions can yield moderate decreases in savings. Rob Thomson explained further that the iterative nature of the SCUC model makes the starting point of the optimization key to the results. Since the starting point of the test Run 1 differs from the starting point of the base Run 1, due to the expansion of the on-peak offer hours, this type of change in production costs is not unlikely.

Stakeholder questioned why the 16 hour on-peak period was implemented. Antoine stated that this represented the traditional on-peak period and much of the pre-
implementation testing was conducted based on these hours. Jim Case stated that during that testing, violations tended to occur less frequently during this 16 hour period.”

Limitation of On-Peak Only Offer Period Testing
HE6-23

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It is the ICTs belief that to fully encompass the current off-peak hours in the WPP significant upgrades would need to be made to the WPP hardware and software technology. During the initial implementation phase of the WPP, the original scope included a 24 hour offer period and it was determined that the current technology would not support this. This initial scope and related development, including 70+ versions of the WPP models prior to implementation was a major contributor to the deviations in the original implementation schedule and costs to implement the WPP.
DATE: April 8, 2010

FROM: E-RSC Working Group

TO: Mark McCulla
    Kimberly Despeaux

SUBJ: Request for Information

During the March 18 Entergy Regional State Committee (E-RSC) Meeting, the E-RSC Working Group has identified the following questions or action items for your immediate attention. Please provide us this information by the date identified below. If you have any clarifying questions or would like to discuss the timelines provided, please contact Sam Loudenslager, at 501-682-5824 or via email at sloudenslager@psc.state.ar.us.

1) **TLR Reports** – The E-RSC agreed that the Local Area Procedure (LAPs) events should be reported with TLR events. The E-RSC will direct changes in how Entergy and the ICT will report TLRs and LAPs; specifically, increasing details. Currently the E-RSC Working Group is developing the reporting form for TLRs and LAPs. While this is being finalized, the E-RSC Working Group wants to verify that Entergy can report the use of LAPs in a format similar to TLR reports. **Action Requested:** By 4:00 pm CDT on April 9, 2010, please confirm in writing Entergy’s ability to provide the LAPs in the same reporting format and timeframe as the TLRs are reported. If this is not feasible, Entergy is to explain why. Please send this response by email to: ERSCWorkingGroup@SPP.org.

2) **WPP Performance** – The E-RSC wants to know the portion of Entergy load that is served through the WPP. **Action Requested:** Entergy is to report this information for each of the months the WPP has been operational by 4:00 CDT on April 9, 2010 and by email to: ERSCWorkingGroup@SPP.org. Also, Entergy is to report this information each month prospectively. These reports are due to the by email to: ERSCWorkingGroup@SPP.org on the 15th business day of each month by 4:00 CPT.

3) **Planning Horizon:** The E-RSC agreed that the three-year process is not adequate and that a 10-year horizon may not be appropriate. Entergy will conduct analyses on 5 and 10-year planning horizons for the Entergy System, broken down by each jurisdiction. To the extent an 8 year analysis can be performed at the same time, Entergy will in good faith pursue such analysis. **Action Requested:** By 4:00 CDT on Friday, April 15, Entergy shall provide to the E-RSC Working Group, by email to ERSCWorkingGroup@SPP.org, a
statement providing the scope, methodology, and timeline Entergy will take to complete this analysis. The analysis is to be completed by May 14, 2010.

4) **CRA Study on Eliminating Rate Pancaking**: At the March 18 meeting, the E-RSC requested Entergy to take the results of the CRA March 23, 2009 study, without modification, on the elimination of rate Pancaking between SPP and Entergy and flow these results through the Entergy System agreement mechanism to determine the economic impact for each Entergy Operating Company. **Action Requested**: By 4:00 CDT on April 15, 2010, Entergy is to provide the results of this analysis. This information should be sent via email to: [ERSCWorkingGroup@SPP.org](mailto:ERSCWorkingGroup@SPP.org).

5) **Entergy OATT & Attachments**: **Action Requested**: By 4:00 CDT on April 12, a copy of the entire Entergy OATT, Attachments and Business Practices are to be provided in Word files (not PDF). These should be sent in the same file format as shown on the Entergy OASIS (e.g., the preamble is in one file, and each attachment is in a separate file). Please send these files to Sam Loudenslager at [sloudenslager@psc.state.ar.us](mailto:sloudenslager@psc.state.ar.us).

The ERSC WG expects that responses to this request will be accurate and complete. To the extent that you believe additional information or data is required to ensure an accurate response, you have an obligation to timely identify and provide that information or data in good faith.

The E-RSC Working Group will be requesting additional information in the coming weeks and in the meantime, appreciates your assistance by providing the information and in the timeframe requested.
DATE: April 8, 2010
FROM: E-RSC Working Group
TO: Mark McCulla
Kimberly Despeaux
SUBJ: Request for Information

During the March 18 Entergy Regional State Committee (E-RSC) Meeting, the E-RSC Working Group has identified the following questions or action items for your immediate attention. Please provide us this information by the date identified below. If you have any clarifying questions or would like to discuss the timelines provided, please contact Sam Loudenslager, at 501-682-5824 or via email at sloudenslager@psc.state.ar.us.

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Response: In the April 8, 2010 meeting ESI reviewed the metrics that SPP uses to report on TLR information, transmission usage, and project tracking. It was agreed that the market type of information used by SPP is not applicable for the Entergy footprint. With respect to the remaining metrics, ESI discussed the feasibility of preparing TLR reports similar to the formats of SPP’s reports 1a, 1b, 1c, and 1f. Report 1c provides a breakdown of TLR levels, and since the LAP process does not have levels associated with it, ESI is responding to this request based on the assumption that report 1c would not be applicable or required with respect to any enhanced reporting of LAP’s.

Based on discussions with Carl Monroe and the E-RSC Working Group, it is ESI’s understanding that the LAP information to be reported will reflect the duration of the LAPs (number of hours) and MWhs involved. ESI currently
believes this information can be provided and reported. However, because ESI has not historically collected this information in this manner, reporting the number of hours and MWhs associated with LAPs will require the historical data to be collected through a manual process. At this point, ESI believes that it can provide 2010 information on LAP’s for reports 1a, 1b and 1f by next week. ESI will continue to work on collecting all of the information that will be needed to match the timeframe of the TLR information and believes that it can accomplish that by May 31st.

2) **WPP Performance** – The E-RSC wants to know the portion of Entergy load that is served through the WPP. **Action Requested:** Entergy is to report this information for each of the months the WPP has been operational by 4:00 CDT on April 9, 2010 and by email to: ERSCWorkingGroup@SPP.org. Also, Entergy is to report this information each month prospectively. These reports are due to the by email to: ERSCWorkingGroup@SPP.org on the 15th business day of each month by 4:00 CPT.

Response: See below

<table>
<thead>
<tr>
<th>Month of NAR</th>
<th>Entergy NAR</th>
<th>Weekly(WPP)</th>
<th>% of NAR</th>
</tr>
</thead>
<tbody>
<tr>
<td>200901</td>
<td>8,918,588</td>
<td></td>
<td></td>
</tr>
<tr>
<td>200902</td>
<td>7,481,837</td>
<td></td>
<td></td>
</tr>
<tr>
<td>200903</td>
<td>8,118,690</td>
<td></td>
<td></td>
</tr>
<tr>
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<tr>
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<tr>
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<tr>
<td>201003</td>
<td>8,435,693</td>
<td>164,721</td>
<td>2.0%</td>
</tr>
</tbody>
</table>

NAR – Net Area Load
3) **Planning Horizon:** The E-RSC agreed that the three-year process is not adequate and that a 10-year horizon may not be appropriate. Entergy will conduct analyses on 5 and 10-year planning horizons for the Entergy System, broken down by each jurisdiction. To the extent an 8 year analysis can be performed at the same time, Entergy will in good faith pursue such analysis. **Action Requested:** By 4:00 CDT on Friday, April 15, Entergy shall provide to the E-RSC Working Group, by email to [ERSCWorkingGroup@SPP.org](mailto:ERSCWorkingGroup@SPP.org), a statement providing the scope, methodology, and timeline Entergy will take to complete this analysis. The analysis is to be completed by May 14, 2010.

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The E-RSC Working Group will be requesting additional information in the coming weeks and in the meantime, appreciates your assistance by providing the information and in the timeframe requested.
Response of: Entergy Services, Inc. on behalf of the Entergy Operating Companies (collectively, “Entergy”) to the April 8, 2010 Data Request of Requesting Party: E-RSC Working Group

Question No.: E-RSC 1-3 Part No.: Addendum:

Question:

**Planning Horizon:** The E-RSC agreed that the three-year process is not adequate and that a 10-year horizon may not be appropriate. Entergy will conduct analyses on 5 and 10-year planning horizons for the Entergy System, broken down by each jurisdiction. To the extent an 8 year analysis can be performed at the same time, Entergy will in good faith pursue such analysis. **Action Requested:** By 4:00 CDT on Friday, April 15, Entergy shall provide to the E-RSC Working Group, by email to ERSCWorkingGroup@SPP.org, a statement providing the scope, methodology, and timeline Entergy will take to complete this analysis. The analysis is to be completed by May 14, 2010.

Response:

The issue.

First, this is not an analysis of planning horizons. Entergy already has a ten-year planning horizon and a ten-year transmission plan. That ten year transmission plan is updated every year and in fact changes every year, as system conditions change, including changes in load forecasts, changes in network resource designations and transactions, and changes in generation in neighboring regions.

As Entergy understands the proposal before the E-RSC, it would change the way that transmission service is granted. Currently, the model that is used for evaluating long-term transmission service requests (“TSRs”) is based solely on the current transmission configuration. Importantly, however, in evaluating TSRs, overloads caused by the requested transmission service that are expected to be resolved by the transmission upgrades that are in the ICT’s current Base Plan are disregarded, and no upgrade costs are charged to the requesting transmission customer to resolve these overloads. The ICT’s Base Plan includes all projects that the ICT has determined must be commenced within the next three years, reflecting the ICT’s view of what is required to serve load reliably, where load includes forecasted native load plus any long-term

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1 The ICT Base Plan and Entergy Construction Plan include projects with in-service dates beyond the three-year horizon. These are included because work on the upgrade must begin within the current three-year horizon in order to meet the needed in-service date.
transmission service commitments including rollover rights. The proposal before the E-RSC would change the current practice, so that no upgrade costs would be charged to requesting transmission customers if the identified overloads were expected to be resolved either by projects that are in the ICT’s Base Plan or by projects that are in Entergy’s ten-year transmission plan for reliability reasons. The details of how this would be implemented would have to be developed.

The current practice and the proposed change are described in more detail below.

**Current practice**

In accordance with FERC requirements, a long-term TSR is evaluated through a System Impact Study (“SIS”). The change in flows that would be created by the new transmission service is currently evaluated against the transmission configuration described above (current configuration, with any overloads that are expected to be addressed by projects in the current ICT Base Plan disregarded). If overloads beyond those expected to be addressed by the projects in the current ICT Base Plan are identified, then the transmission service cannot be granted without an upgrade. Under Attachment T of Entergy’s OATT, if the required upgrade is in the ICT’s Base Plan, then the requesting customer is not required to fund the upgrade. If the required upgrade is not in the ICT Base Plan, then the upgrade is considered Supplemental and the transmission customer is required to pay for it in order for the service to be granted. This pricing policy is generally referred as “participant funding.” There is currently no evaluation of whether or not the upgrade required for the TSR is in the ten-year transmission plan.

Note that once a customer has funded a Supplemental upgrade, if there is excess capacity on that upgrade above and beyond what the funding customer uses, and that excess capacity turns out to be needed in future years to serve load reliably, the funding transmission customer is reimbursed on a pro rata basis for the portion of the upgrade cost that is now associated with reliability.

**Proposed Change in practice**

Under the current practice, if an upgrade is identified in the SIS as required for a TSR and it happens to be in the ten-year plan, it is still subject to participant funding as long as it is not in the ICT’s three-year Base Plan. Under the proposed change, that same upgrade would not be subject to participant funding. The new long-term service would be granted without any upgrade costs being allocated solely to the requesting transmission customer and from then on the new long-term service would be included in the model for transmission planning purposes.

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2 For long-term Point-to-Point transmission service requests, the application of FERC’s “higher of” pricing methodology in the Entergy OATT could determine that the upgrades required for that service be rolled into transmission rate base.

3 The use of the term “load” also includes all firm uses on the transmission system.
The Implications

As noted, the proposal before the E-RSC does not represent a change in planning horizon. It is a change in the way transmission service is granted, which will lead to a change in the way that costs are allocated, and may actually change what transmission upgrades are built. In fact, the proposal could lead to uneconomic investments being made and paid for by native load (i.e., the native load customers of the Entergy Operating Companies who ultimately bear an overwhelming majority of the cost of transmission upgrades deemed necessary for reliability).

In particular, there could be an upgrade that (a) shows as needed for reliability in the “out years” of a ten-year plan, and (b) is identified in an SIS for a TSR, and (c) turns out NOT to be needed for reliability due to changing conditions and is ultimately dropped from the ten-year plan or deferred. Under the proposed change, the upgrade would not be charged to the TSR customer; the TSR would be granted, and the upgrade would likely turn out to be needed solely because the TSR was granted and became part of the load forecast – a self-fulfilling prophecy. Once the upgrade was within the three-year horizon, it would likely become part of Entergy’s Construction Plan and the ICT’s Base Plan because of the service that was granted that relied on the upgrade.

The upshot is that Entergy’s native load customers could end up funding upgrades that, in fact, were not needed for reliability (absent the self-fulfilling prophecy). In addition, the incremental revenue from the TSRs could be zero if the TSRs were requests for new long-term network resources, as, absent participant funding, there is no incremental transmission revenue associated with new network resources.

The key question as to how much of a risk the proposal before the E-RSC poses to Entergy’s native load customers is how much the five- or ten-year transmission plan evolves over time. The more it evolves, the greater the risk that Entergy’s native load customers will fund the lion’s share of the cost of upgrades that actually were not necessary for reliability and instead inure primarily to the benefit of another transmission customer. The analysis that Entergy proposes to conduct, which is described below, is an effort to answer this key question.

The Analysis

In response to this data request, Entergy will conduct an analysis of several past ten-year transmission plans to identify how much the plans evolved over time. Entergy will go back as far as 2000 if possible. Entergy will use data submitted in the FERC Form 715 - Annual Transmission Planning and Evaluation Report as well as data from the annual transmission planning summits. The evolution of the plan can be tracked year by year – for instance, upgrades that are identified to be needed in the tenth year of the plan in year X become the upgrades needed in the ninth year of the plan in year X +1; and so on – unless the needs of the system change.

Entergy notes that it has developed the methodology for the proposed analysis on an expedited basis in order to facilitate prompt review and input from the E-RSC Working Group. Entergy reserves the right, in consultation with the E-RSC Working Group, to modify the methodology of the analysis outlined in this response as work on the analysis proceeds.
There are a number of reasons why an upgrade identified as needed in a particular ten-year plan could become no longer needed in subsequent plans, including changes in load forecast, reconfiguration of network resources, sale of long-term service providing loading relief to the affected element, or a change in the configuration of resources and facilities in adjacent transmission systems. A transmission project in a particular ten-year transmission plan may in a subsequent ten-year plan be deferred beyond the previously expected in-service date for these same reasons.

From the reports and using available information on actual construction of facilities as well as adjusting for the substitution of one upgrade or set of upgrades for another, the following metrics will be calculated:

- % of projects built on a schedule consistent with that originally identified
- % of projects deferred more than 2 years
- % of projects phased out of the long-term plan and never included in the Construction Plan

Depending on the availability of the data that was used in the planning process at the time for each of these years, Entergy will also attempt to further refine the analysis for three categories of projects to produce the following set of statistics:

- For projects with a date of “need” in years 4 & 5 of the long-term transmission plan:
  - % of projects built on a schedule consistent with that originally identified
  - % of projects deferred more than 2 years
  - % of projects phased out of the long-term plan and never included in the Construction Plan

- For projects with a date of “need” in years 6, 7 & 8 of the long-term transmission plan:
  - % of projects on a schedule consistent with that originally identified
  - % of projects deferred more than 2 years
  - % of projects phased out of the long-term plan and never included in the Construction Plan

- For projects with a date of “need” in years 9 & 10 of the long-term transmission plan:
  - % of projects on a schedule consistent with that originally identified
  - % of projects deferred more than 2 years
  - % of projects phased out of the long-term plan and never included in the Construction Plan

Entergy may also provide an analysis of the potential cost implications of the proposal for native load customers. In addition, Entergy may identify one or more specific examples of upgrades that “dropped out” of a ten-year plan and fit the criteria listed above, namely: the upgrade (a) shows as needed for reliability in the “out years” of a ten-year plan, and (b) is identified in an SIS for a TSR, and (c) turns out NOT to be needed for reliability due to changing conditions and
is ultimately dropped from the ten-year plan or deferred. Entergy will identify the dollars associated with the upgrade that would have been assigned to Entergy native load customers had the proposed new practice been in effect. Entergy will also identify the incremental revenues, if any, that the TSRs would have provided to offset the cost of the upgrade had the proposed new practice been in effect. As noted above, TSRs for designation of network resources do not result in incremental transmission revenues in the absence of participant funding.
Response of: Entergy Services, Inc. on behalf of the Entergy Operating Companies (collectively, “Entergy”) to the April 8, 2010 Data Request of Requesting Party: E-RSC Working Group

Question No.: E-RSC 1-4 Part No.: Addendum:

Question:

CRA Study on Eliminating Rate Pancaking: At the March 18 meeting, the ERSC requested Entergy to take the results of the CRA March 23, 2009 study, without modification, on the elimination of rate pancaking between SPP and Entergy and flow these results through the Entergy System agreement mechanism to determine the economic impact for each Entergy Operating Company. Action Requested: By 4:00 CDT on April 15, 2010, Entergy is to provide the results of this analysis. This information should be sent via email to: ERSCWorkingGroup@SPP.org.

Response:

In order to accurately determine how the savings from the CRA study on eliminating rate pancaking would flow through the Entergy System Agreement and affect each Entergy Operating Company’s costs, an hour-by-hour analysis would have to be performed to determine how each Operating Company’s owned resources and allocated portion of purchase power match that Company’s load requirements. Entergy does not have this level of detail from the CRA analysis; it also could not complete such analysis in the timeframe specified for this response. Accordingly, Entergy has performed a simplified analysis that allocates to the Operating Companies based on a load responsibility ratio (1) the scaled production cost savings and lost transmission revenues used by CRA in its original study and (2) the unadjusted production cost savings from the GE MAPs model and the corrected loss pancake transmission revenues that Entergy previously identified. The attached spreadsheet contains the results of this analysis. It is important to note that the simplified analysis provided in this response is not a reliable substitute for the allocation of production costs required pursuant to the Entergy System Agreement. Accordingly, Entergy notes that it currently contemplates performing the hour-by-hour analysis required pursuant to the System Agreement for purposes of allocating the

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1 CRA used an incomplete data set to calculate the lost revenues associated with elimination of the transmission pancake between Entergy and SPP and so considerably understated the cost of the loss of these revenues in its analysis. CRA also “scaled” the production cost savings from the GE MAPs model run to reflect the difference between the historical level of transactions between SPP and Entergy, and those predicted by the model.
production costs and benefits identified in the ICT/SPP RTO study currently being performed by CRA; Entergy, in coordination with the FERC Staff, will work with CRA to obtain the necessary hourly information from CRA.
Allocation of Net Benefit/Cost of Elimination of Transmission Pancaking from CRA Study

CRA Original Case:

Production cost savings = 7.3 $MM Adjusted Production Cost Change for Entergy Region from CRA Model (Scaled) - 2010 Projected
Lost PTP Transmission Revenues = (2.9) $MM Average Lost Revenues 2006-2008 as calculated by CRA/SPP using incomplete data

<table>
<thead>
<tr>
<th>Allocation Using 2008 LRRs</th>
<th>EAI</th>
<th>ELL</th>
<th>EMI</th>
<th>ENO</th>
<th>EGSL</th>
<th>ETI</th>
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<tbody>
<tr>
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<td>0.86</td>
<td>0.66</td>
<td>4.40</td>
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Entergy Corrected Case:

Production cost savings = 9.0 $MM Unadjusted Production Cost Change for Entergy Region from CRA Model - 2010 Projected
Lost PTP Transmission Revenues = (14.0) $MM Average Lost Revenues 2006-2008 using correct data

<table>
<thead>
<tr>
<th>Allocation Using 2008 LRRs</th>
<th>EAI</th>
<th>ELL</th>
<th>EMI</th>
<th>ENO</th>
<th>EGSL</th>
<th>ETI</th>
<th>Total</th>
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<td>(0.21)</td>
<td>(0.98)</td>
<td>(0.75)</td>
<td>(5.00)</td>
</tr>
</tbody>
</table>

Notes:
Since Entergy does not access to the details of the unit dispatch used in the CRA model, production cost savings and lost transmission revenues have been allocated using the operating companies Load Responsibility Ratios.
The production cost savings are lower in the original CRA case since CRA in their analysis scaled the results of the GE Maps model based on the ratio of historical transactions between the regions and those captured in the model. We used the unadjusted production cost savings from the CRA GE Maps model run for 2010 in the corrected case.